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Evaluation of the Technological Feasibility, and Cost of Selected Control Alternatives Necessary to Meet the Proposed Ohio SO2 Regulations for Industrial Boilers and Processes. Volume IX. Union Camp Corporation, Chemical Division, Dover Plant

GCA Corp, Bedford, Mass. GCA Technology Div.

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Environmental Protection Agency, Chicago, Ill. Air and Hazardous Materials Div.

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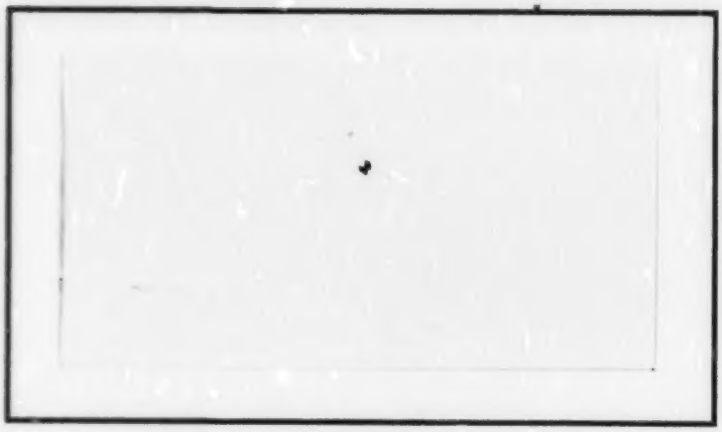

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EVALUATION OF THE TECHNOLOGICAL FEASIBILITY, AND COST OF SELECTED CONTROL ALTERNATIVES NECESSARY TO MEET THE PROPOSED OHIO SO_2 REGULATIONS FOR INDUSTRIAL BOILERS AND PROCESSES

FINAL REPORT

Contract No. 68-01-3155
Task Order No. 4

August 1976

Volume IX

UNION CAMP CORPORATION,
CHEMICAL DIVISION, DOVER PLANT

by

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16. ABSTRACT
This report presents an evaluation by the GCA Corporation, GCA/Technology Division, of technological feasibility and cost of complying with the proposed Ohio SO_2 regulation (40 FR 52410, November 10, 1975) at the Union Camp Corporation, Chemical Division's Dover Plant. The final USEPA Sulfur Dioxide Control Strategy for the State of Ohio Technical Support Document , Vol. I and II (EPA 905/2-76-002) may be obtained from NTIS.

This plant produced fatty organic chemicals. Two small coal-fired boilers are operated to produce steam for the production of these chemicals. After collecting necessary site and process specific data by means of a plant visit, the technical feasibility and cost of commercial lime and double alkali scrubbing systems were evaluated.

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ABSTRACT

Union Camp Corporation, Chemical Division, Dover Plant, produced fatty organic chemicals. Two small coal-fired boilers are operated at Union Camp to produce steam for the production of these chemicals. The results of an evaluation of the technical feasibility and cost of complying with the proposed Ohio SO_2 regulation of 3.2 lb $SO_2/10^6$ Btu applicable to these boilers are presented in this report.

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SECTION I

SUMMARY AND CONCLUSIONS

Union Camp Corporation was selected as an example facility operating small industrial coal-fired boilers. The technical feasibility, and cost, of meeting the proposed Ohio SO_2 regulation for fossil fuel fired steam generators at this facility were evaluated. Union Camp is affected by the Tuscarawas County regulation limiting SO_2 emissions to 3.2 lb/10^6 Btu fuel input.

Two stoker fired boilers with capacities of 76 × 10^6 Btu/hr and 123 × 10^6 Btu/hr are operated by Union Camp to produce process steam. These boilers currently burn 40,000 tons of coal per year containing 3.4 percent sulfur. The SO_2 emission rate is 6.5 lb/10^6 Btu and would need to be reduced 51 percent to comply with the proposed regulation.

The technical feasibility, and cost, of commercial lime and double alkali wet scrubbing systems were evaluated. The two systems considered in this study are produced specifically for industrial boilers. Total capital requirements for these systems were $1.8 to $1.9 million. Annual operating costs were $360,000 per year. Total annual costs including operation, depreciation, cost of capital, and federal taxes were $574,000 to $588,000 per year. These annual costs are equivalent to $0.40 to $0.41 per pound of sulfur removed or $0.66 to $0.67 per 10^6 Btu of coal burned.

The present price of compliance coal containing about 1.7 percent sulfur was also evaluated. At the present time this cost differential is only $0.028 to $0.053/$10^6$ Btu of coal burned. This is equivalent to an annual cost of $24,000 to $46,000.

SECTION II

PROCESS AND SITE DESCRIPTION

The Union Camp Corporation Chemical Division, Harchem Division Plant, was visited 7 April 1976. This facility, located in Dover, Ohio, Tuscarawas County, produces fatty organic chemicals. Approximately 40,000 tons of coal averaging about 3.4 percent sulfur are consumed annually to generate process steam. Annual SO_2 emissions are 2800 tons per year. The purpose of the plant visit was to collect site and process specific data necessary to determine the technical feasibility and cost of complying with the proposed regulations for control of SO_2 emissions from coal-fired boilers. Mr. V. P. Bedrosian, Plant Manager, and Mr. William R. Morgan, Plant Engineer, represented Union Camp. Boiler design and operating data along with boiler house and site layout diagrams were provided by Union Camp.

The Dover Plant boiler facility consists of two spreader stokers (Nos. 9 and 11) which were installed in 1952 and 1967, respectively. Union Camp estimates the remaining life of these boilers to be 20 years.

The particulate emissions from boilers Nos. 9 and 11 are controlled by mechanical collectors which were installed in 1952 and 1967, respectively. Cleaned flue gases from these two units vent to two separate stacks. In order to comply with the Ohio State particulate emission limitations, Union Camp is in the process of installing new mechanical collectors. One mechanical collector will replace the collector presently on boiler No. 9 while the second will operate in series, handling the flow from the new No. 9 collector and the old No. 11 collector. The installation

of these units is expected to be completed by the end of July 1976. Tuscarawas County is in the Zanesville-Cambridge Intrastate Air Quality Control Region (AQCR 183) which is a Priority II Region for particulates. The boilers at Union Camp, which have a combined rate capacity of 199 x 10^6 Btu/hr input, are limited by the regulations to emissions of 0.25 lb particulate/10^6 Btu input. The bottom ash and fly ash that are generated by the two spreader-stoker units are handled dry and are trucked to an off site disposal site.

Table 1 presents pertinent design and operating data for the two boilers at Union Camp. Barring unscheduled outages, Union Camp operates their boilers 24 hr/day, 365 day/yr. Table 2 presents the typical coal sulfur and ash contents, heating value and consumption rate. Union Camp purchases their coal from the Puskarich Mining Company. Coal is transported to the plant by truck from local mines. They did not disclose their coal cost but we estimate it to be in the vicinity of $23/ton.

According to the proposed regulation §52.1881(b)(2) the allowable SO_2 emission rate for fossil fuel-fired steam generators in Tuscarawas County is 3.2 lb $SO_2/10^6$ Btu. The typical sulfur content and heating value of the coal combusted at Union Camp are 3.4 percent and 10,500 Btu/hr, respectively. Assuming 100 percent of the sulfur in the coal is converted to SO_2, the emission rate is 6.48 lb $SO_2/10^6$ Btu input. To meet the proposed limits, the SO_2 emissions would have to be reduced by 51 percent.

Figure 1 presents a schematic of the Union Camp boiler site. As illustrated by this figure, there are approximately 875 square feet of available open area near the boilers that might serve as a site for a flue gas desulfurization system. Vertical diagrams of Union Camp's new mechanical collectors, ducting and stacks for boilers No. 9 and 11 are presented in Figures 2 and 3, respectively. As shown by these figures, the location of the induced draft fans, the limited lengths of

Table 1. UNION CAMP BOILER DESIGN AND OPERATING DATA

	Spread stokers	
	No. 9	No. 11
Rated capacity, 10^6 Btu/hr input	76	123
Normal operating rate, 10^6 Btu/hr input	32	80
Stack gas temperature, °F	400	390
Stack gas flow at rated capacity, scfm	22,480	34,750
Stack gas flow at normal operating rate, scfm	9,370	22,110
Excess air, percent	62-119	47-76
SO_2 concentration in stack gas, ppm[a]	2,235	2,340
SO_2 emission rate, lb $SO_2/10^6$ Btu input[a]	6.48	6.48
Allowable SO_2 emission rate, lb $SO_2/10^6$ Btu input	3.2	3.2

[a]These values were calculated based on the assumption that 100 percent of the sulfur in the coal is converted to SO_2.

Table 2. TYPICAL COAL ANALYSIS AND CONSUMPTION

Sulfur content, percent	3.4
Ash content, percent	17.0
Heating value, Btu/lb	10,500
Annual consumption, tons/yr	40,000

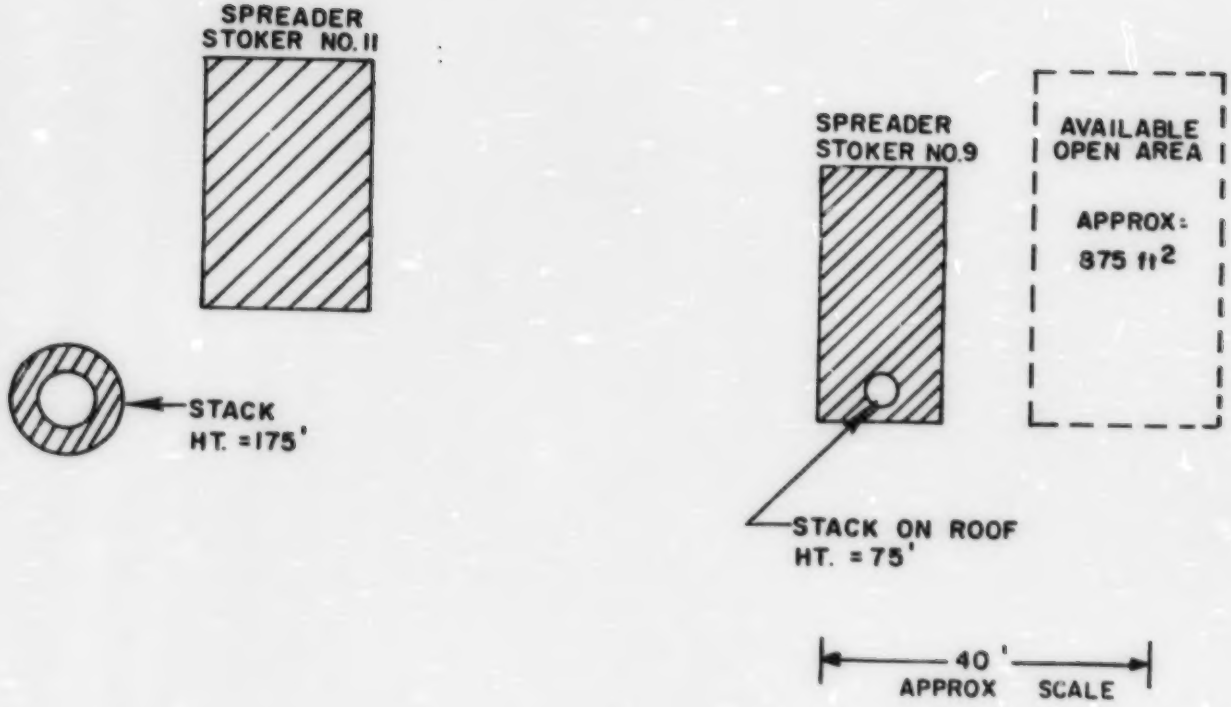

Figure 1. Union Camp boiler site

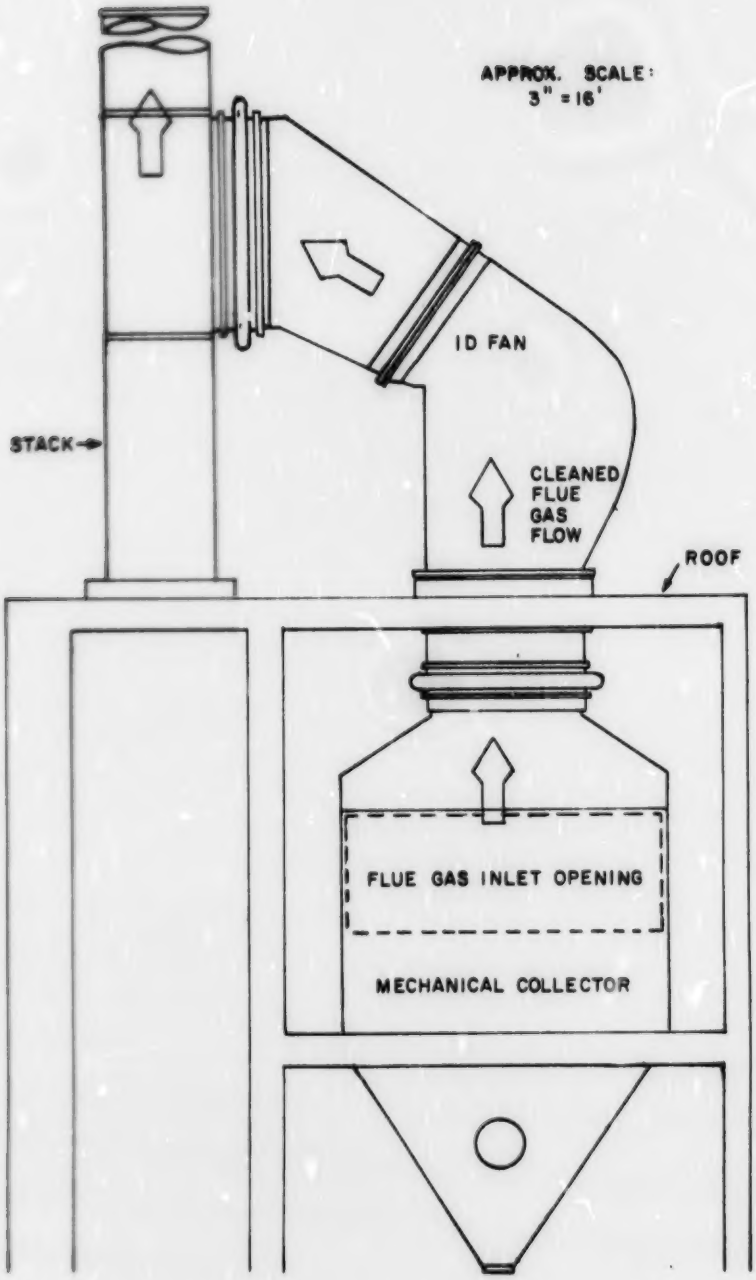

Figure 2. Vertical diagram of mechanical collector on Union Camp No. 9 boiler

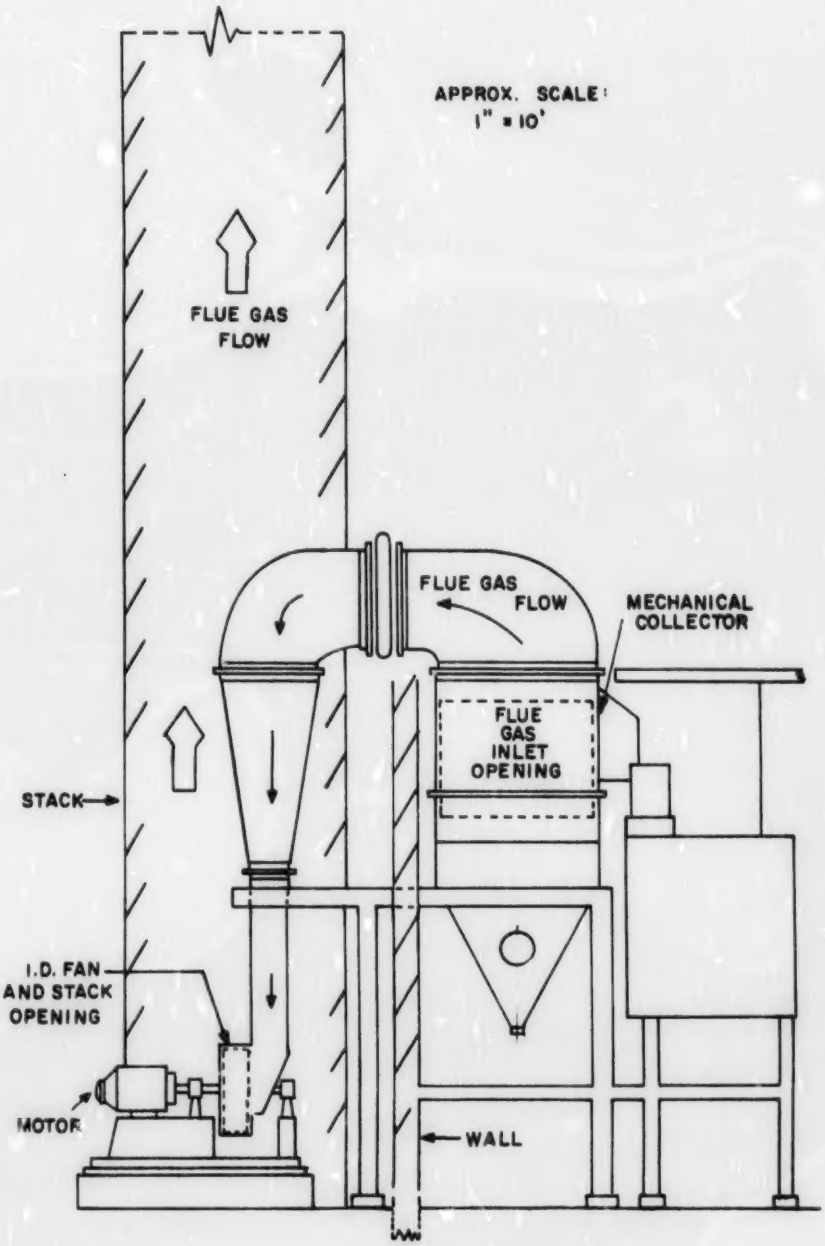

Figure 3. Vertical diagram of mechanical collector on Union Camp No. 11 boiler

ducting runs and the close clearances would increase the cost of retrofitting a flue gas desulfurization system to these boilers.

SECTION III

SO_2 CONTROL METHODS FOR SMALL COAL-FIRED BOILERS

Emissions of SO_2 from Union Camp's boilers can be reduced to comply with the proposed limit of 3.2 $lb/10^6$ Btu by flue gas desulfurization or switching to a lower sulfur coal. If flue gas desulfurization was selected then a system to clean 33,000 scfm at a 90 percent SO_2 collection efficiency would be needed. An alternative would be to use a compliance coal such as a coal with a heating value of 12,000 Btu/lb containing 1.9 percent sulfur.

FLUE GAS DESULFURIZATION SYSTEMS

There are many flue gas desulfurization processes either currently in use or under development for control of SO_2 emissions from coal-fired boilers. These methods include wet scrubbing with lime, limestone, magnesium oxide, sodium sulfite (Wellman-Lord), sodium hydroxide (double alkali) and sodium citrate. Catalytic oxidation, dry adsorption on carbonaceous materials, absorption by molten carbonate and other processes are also being developed. Many of these processes are not applicable to small industrial coal-fired boilers due to the poor economics of small scale systems. GCA has selected the Bahco system, a wet scrubbing process using lime, manufactured by Research-Cottrell and the FMC double alkali system for evaluation in this study. These two systems were selected because they are specifically designed and marketed for application to industrial coal-fired boilers and because the technology has been demonstrated.

Lime Scrubbing

Lime scrubbing systems are manufactured by numerous engineering construction firms and have been in use on utility boilers for several years. Although lime scrubbing is very similar to limestone scrubbing there are several potential advantages of using lime, particularly for smaller systems. Raw material transport costs are lower, maintenance and scaling may be reduced, raw material utilization is more effective, and solid waste quantities are slightly lower. Table 3 summarizes the status of lime scrubbing systems.

The Research-Cottrell* Bahco lime scrubbing system (see Figure 4, consists of a two stage venturi. The first venturi presaturates the gas, removes some SO_2 and may be designed to remove particulates. At the bottom of the column, flue gas is directed down against the surface of a milk of lime slurry. The high velocity gas liquid contact produces a vigorous cascade of droplets that carry up into the first scrubber stage for turbulent mixing with the flue gas. Above the first venturi, droplets are separated in an inertial collector while the gas continues up to a second stage. Here the gas liquid contact process is repeated. A mist eliminator above the second stage frees the gas of droplets prior to exiting out the stack. Separated liquids from both stages of the venturi return to the lower impingement zone. A fraction of this return flow is continuously removed for disposal, usually to a thickener. Clarified liquid is returned to the lime dissolving tank to minimize makeup requirements.[1] Operating and design characteristics of the Bahco system are summarized in Table 4.

---

*Research-Cottrell, P.O. Box 750, Bound Brook, N.J.

Table 3. STATUS OF LIME FLUE GAS DESULFURIZATION SYSTEMS AS OF 5/76[2,3]

Utility company power station	Size of FGD unit, MW[a]	Vendor/process	Fuel characteristics	Startup date, mo/yr	Availability, %
Operational systems					
Duquesne Light Elrama	510	Chemico/ Lime Scrubbing	Coal - 1.0 - 2.8 percent sulfur	10/73	-
Duquesne Light Phillips	410	Chemico/	Coal - 1.0 - 2.8 percent sulfur	7/73	73
Kentucky Utilities Green River - Units 1 & 2	64	American Air Filter/ lime scrubbing	Coal - 3.8 percent sulfur	10/75	-
Louisville Gas & Electric Paddys Run No. 6	65	Combustion Engineering/ lime scrubbing	Coal - 3.5 - 4.0 percent sulfur	4/73	56
Montana Power Co. Colstrip No. 1	360	Combustion Equip. Associates/ lime scrubbing	Coal - 0.8 percent sulfur	10/75	-
Rickenbacker AFB Rickenbacker	42	Research Cottrell/ lime scrubbing	Coal - 3.6 percent sulfur	3/76	90
Pennsylvania Power Co. Bruce Mansfield No. 1	835	Chemico/ lime scrubbing	Coal - 4.3 percent sulfur	10/75	8
Tennessee Valley Authority Shawnee No. 10	30	Tennessee Valley Authority lime/limestone scrubbing	Coal - 2.9 percent sulfur	4/72	-
Arizona Public Service Four Corners No. 5A	160	SCE/lime scrubbing	Coal - 0.7 percent sulfur	2/76	-
Systems under construction					
Columbus & Southern Ohio Elec. - Conesville No. 5	400	Universal Oil Products/ lime scrubbing	Coal - 4.5 - 4.9 percent sulfur	6/76	-
Louisville Gas & Electric Cane Run No. 4	178	American Air Filter/ lime scrubbing	Coal - 3.5 - 4.05 percent sulfur	6/76	-
Louisville Gas & Electric Cane Run No. 5	183	Combustion Engineering/ lime scrubbing	Coal - 3.5 - 4.05 percent sulfur	12/77	-
Louisville Gas & Electric Mill Creek No. 3	425	American Air Filter/ lime scrubbing	Coal - 3.5 - 4.0 percent sulfur	7/77	-

[a]One MW is approximately equivalent to 10 x 10^6 Btu/hr fuel input and 2200 scfm flue gas.

Table 3 (continued). STATUS AND LIME FLUE GAS DESULFURIZATION SYSTEMS AS OF 5/76[2,3]

Utility company power station	Size of FGD unit, MW[a]	Vendor/process	Fuel characteristics	Startup date, mo/yr	Availability, %
Systems under construction					
Montana Power Co. Colstrip No. 2	360	Combustion Equip. Associates/ lime scrubbing	Coal - 0.8 percent sulfur	7/76	-
Pennsylvania Power Co. Bruce Mansfield No. 2	835	Chemico/ lime scrubbing	Coal - 4.3 percent sulfur	4/77	-
Utah Power & Light Co. Huntington No. 1	415	Chemico/ lime scrubbing	Coal - 0.5 percent sulfur	1/77	-
Contracts awarded - engineering design phase of development					
Columbus & Southern Ohio Elec. - Conesville No. 6	400	Universal Oil Products/ lime scrubbing	Coal - 4.5 - 4.9 percent sulfur	1/78	-
Allegheny Power System Pleasants No. 1	625	Babcock & Wilcox/ lime scrubbing	Coal - 2.0 - 5.0 percent sulfur	3/79	-
Allegheny Power System Pleasants No. 2	625	Babcock & Wilcox/ lime scrubbing	Coal - 2.0 - 5.0 percent sulfur	3/80	-
Utah Power & Light Co. Emery No. 1	400	Chemico/ lime scrubbing	Coal - 0.5 percent sulfur	6/78	-

[a]One MW is approximately equivalent to 10×10^6 Btu/hr fuel input and 2200 scfm flue gas.

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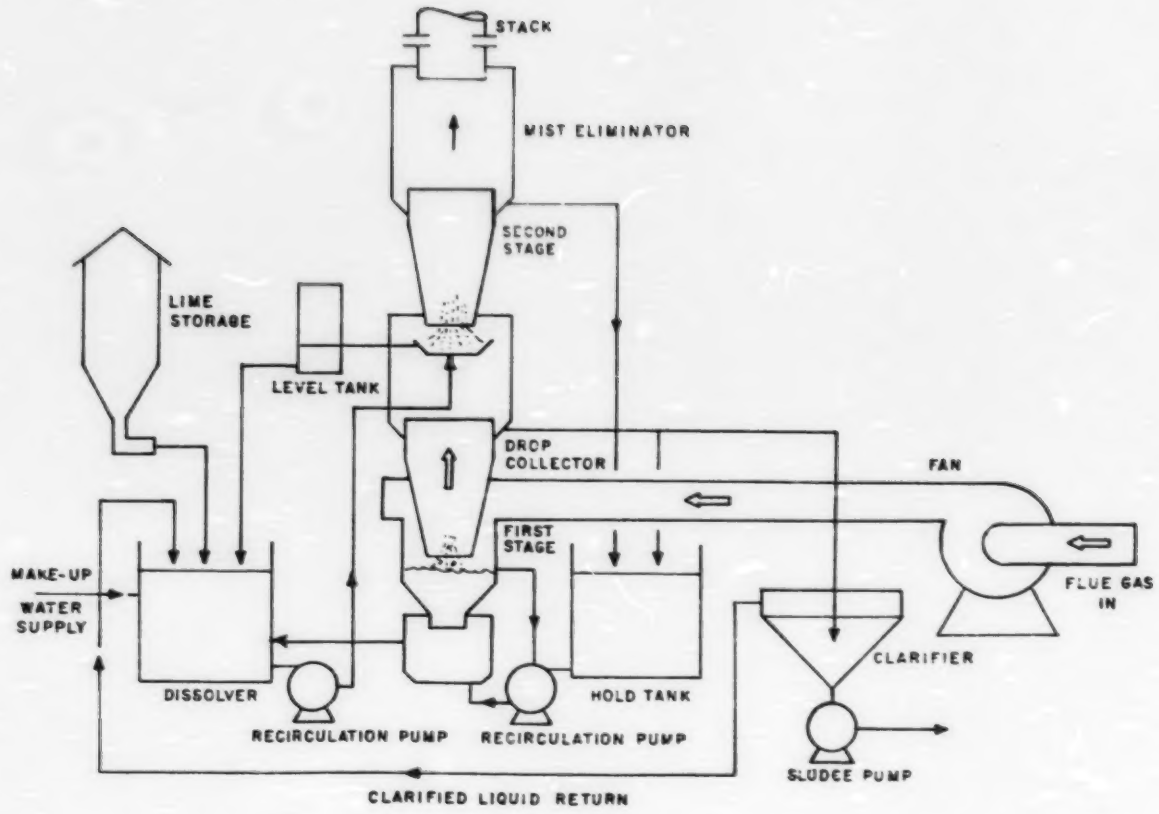

Figure 4. R-C lime (Bahco) scrubber system[1]

Table 4. RESEARCH-COTTRELL LIME (BAHCO) SCRUBBING SYSTEM[3,4]

Smallest system capacity commercially available (scim)	20,000
Overall pressure drop through system (in H_2O)	16 - 26
Turndown ratio of system[a]	1.5 - 1
SO_2 removal efficiency, percent	90 - 99
Raw materials	Lime
By-products	None
Wastes[b] lb waste/lb SO_2 removed	6.1 lb cake containing 35 percent solids ($CaSO_3$ and $CaSO_4$) and 65 percent water
Maintenance	Scaling and solids deposition appear to be less severe than for limestone based scrubbing systems. Corrosion can be minimized by properly designing the system.
Development status	Operational systems 55,000 scfm 3.6% S coal

[a] Any turndown ratio may be accommodated by the addition of makeup air.

[b] Does not included the fly ash that would be removed.

Double Alkali Scrubber Systems

A double alakali scrubber system has been developed by FMC Corporation* and is currently in operation and being marketed commercially. The process involves a sodium-based scrubbing loop in which the sulfur dioxide in flue gas is collected according to the following reactions:

$$Na_2CO_3 + H_2O \rightarrow 2\ NaOH + CO_2$$

$$2NaOH + SO_2 \rightarrow Na_2SO_3 + H_2O$$

$$Na_2SO_3 + SO_2 + H_2O \rightarrow 2NaHSO_3$$

and subsequently precipitated with calcium in a separate loop according to the reaction

$$2NaHSO_3 + Ca(OH)_2 \rightarrow CaSO_3 + Na_2SO_3 + 2H_2O$$

This system was developed primarily to alleviate scaling problems initially encountered with lime/limestone systems. The spent scrubber solution which is primarily composed of sodium bisulfite ($NaHSO_3$) is pumped to a lime reactor where it is mixed with slaked lime. In the reactor, sodium bisulfite is converted to sodium sulfite (Na_2SO_3) and calcium sulfite ($CaSO_3$) is precipitated out, thickened and put through a rotary drum vacuum filter. Due to oxygen in the flue gas, a portion of the sodium sulfite is oxidized to sodium sulfate. These chemical losses are offset with makeup soda ash.[5] A schematic of FMC's double alkali scrubber system is presented in Figure 5. Table 5 presents pertinent design and operating data for the FMC double alakali scrubbing system.

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*FMC Corporation, Environmental Equipment Division, 21 Charles Street, Westport, Conn.

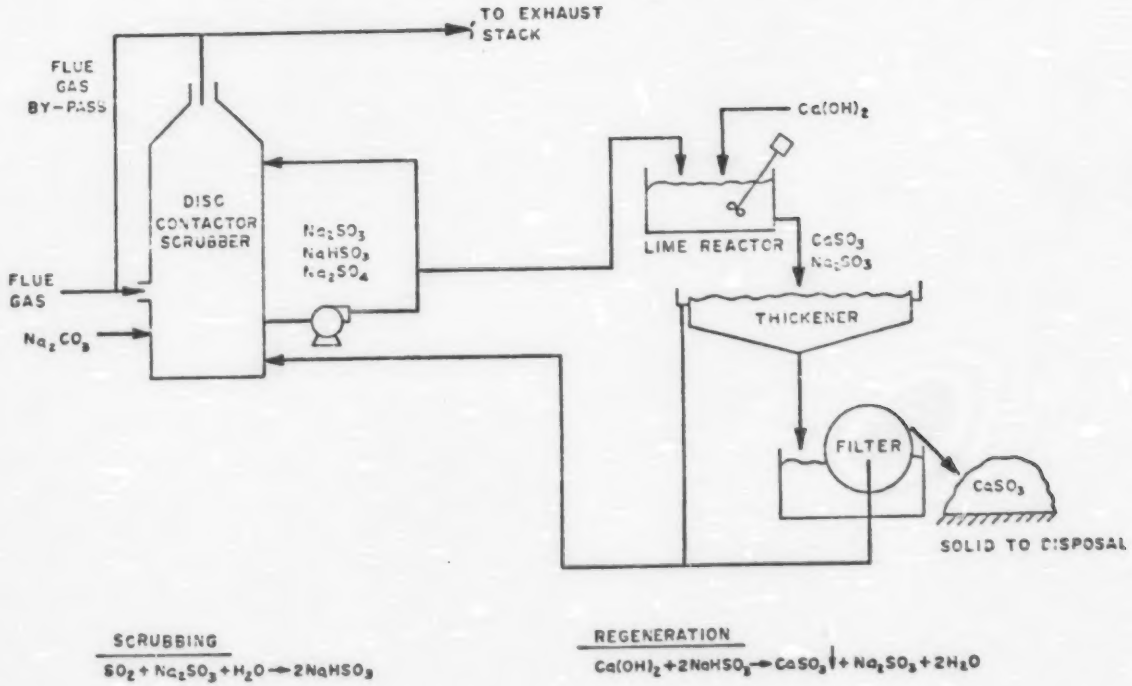

Figure 5. FMC double alkali scrubber system[5]

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Table 5. FMC DOUBLE ALKALI SCRUBBING SYSTEM[6]

Smallest system capacity commercially available (scfm)	33,000
Overall pressure drop through system (in H_2O)	5 - 15
Turndown ratio of system	4:1
SO_2 removal efficiency, percent	90 - 95
Raw materials	Lime (CaO), soda ash (Na_2CO_3)
By-products	None
Wastes[a] lb waste/lb SO_2 removed	5.8 lb sludge cake from clarifier containing 35 percent solids ($CaSO_3$ and Na_2SO_4) and 65 percent water
Maintenance	This system is designed such that scaling is not a problem. Corrosion problems can be minimized with proper system design.
Development status	Operational systems 3 MW; 2 % S coal; 90 % SO_2 removal 94 % availability; operating since 1/75 57 MW; 3.2 % S coal; 90 % SO_2 removal 100 % availability; operating since 10/75 Systems in engineering design and construction phase of development 95 MW; 3.2 % S coal; startup slated for 1977 93 MW; 3.2 % S coal; startup slated for 1978

[a]Does not include the fly ash that would be removed.

Sludge Disposal

Nonregenerative scrubbing systems for SO_2 control produce sludges that must be utilized or disposed. Sludges produced by lime and limestone SO_2 scrubbing systems contain primarily calcium sulfite, calcium sulfate, calcium carbonate and fly ash. Trace metals resulting primarily from coal ash components are also present in the sludge. Water content is typically 50 to 80 percent. An environmentally acceptable method for sludge disposal or utilization must be considered in the evaluation of the technical feasibility and cost of scrubbing. Numerous options have been proposed for sludge utilization[7,8] but significant application of these techniques, especially to small systems like Union Camp, appears to be unlikely. A recent EPA-sponsored study concluded that ponding and landfill are the only near term alternatives for sludge disposal.[9]

Ponding is currently the most commonly used lime/limestone sludge disposal method. All wet scrubbing systems present the potential problem of direct waste water discharge to surface waters. Eight full scale systems representing over 1500 Mw of boiler capacity have eliminated this problem by recirculating the scrubber liquor; i.e., closed loop operation.[10] Other installations recirculate as much of the liquor as technically feasible. Pollution of ground and surface waters from leachate formation is also a potential problem. Ponds may be lined with clay or synthetic materials like asphalt, PVC, Hypalon, etc.[11] The necessity for lining and/or stabilization depends on local regulations, sludge characteristics and local geology and hydrology. Currently, only Commonwealth Edison, Will County No. 1, is using a lined (clay) pond[2] but future requirements will probably be more stringent.

Costs for sludge disposal by ponding can vary very widely, depending on land cost; the type of liner used, if any; location of the pond in relation to the scrubbers; and the settling characteristics of the sludge. The need for a pond liner and the type used and therefore the disposal

cost will depend on local geology, hydrology and environmental regulations. It has been suggested that small industrial boilers may present reduced sludge disposal problems as local environmental impacts will be limited.[12] This is especially true for Union Camp, where only 6100 tons of sludge per year would be generated. Aerospace Corporation has conducted a detailed evaluation of ponding[11] and is currently continuing programs in the area. Data from this initial study have been updated and cost ranges are $0.2 to $3 per ton of sludge (50 percent solids) for unlined pond disposal and $0.5 to $10 per ton of sludge for lined pond disposal.[9] The large range and higher upper limits reflect uncertainty in regard to unusual local situations. A cost of $3 per ton for sludge disposal in a lined pond was reported to be typical. Costs would be nearer $1 per ton if disposal in an unlined pond is allowed. Typical truck hauling rates for stabilized fly ash for a distance of 5 miles are reported to be $0.75/ton.[9] This may represent an added cost when offsite ponding or landfill is required. Based on the above data, GCA used a cost of $4/ton for sludge disposal.

Landfill is also a viable disposal option although use of this option is currently limited. Large scale landfills utilized by utilities would be 1 to 2 orders of magnitude larger than the landfill that would be needed for Union Camp. These large landfills would probably require extensive sludge dewatering and in some cases chemical fixation. Small amounts of dewatered sludge generated by Union Camp might be disposed in a municipal sanitary landfill or mixed with other plant wastes for disposal.

Sludge from sodium-based double alkali systems have been less intensively investigated. A major difference between sludges from lime/limestone systems and double alakali systems is that the former are primarily calcium sulfate ($CaSO_4$) while the latter are primarily calcium sulfite ($CaSO_3$). One might expect, in view of the dewatering problems attributed to minor amounts of $CaSO_3$ in lime/limestone sludge, that double alakali sludge would be difficult to dewater. However, FMC has investigated

vacuum filtration and landfilling of double alkali sludge and reports success in both areas.[5] Perhaps the different conditions under which the sludges form also affects the properties.

While sludge disposal is an important environmental consideration, disposal methods are available and the annual cost should be relatively small, less than 10 percent of the total annual FGD cost.

LOW SULFUR COAL AND OTHER SO_2 EMISSION REDUCTION ALTERNATIVES

The use of low sulfur coal and/or mechanical coal cleaning are potential methods for complying with the proposed SO_2 regulations. These options will be particularly attractive in counties with the least stringent emission limitations.

The sulfur content of coal needed to comply with the proposed regulations varies as the emission limit varies from 0.6 lb $SO_2/10^6$ Btu to 6.8 lbs $SO_2/10^6$ Btu in those counties that are regulated. Therefore, the sulfur content of "low sulfur" or compliance coal needed to comply with the proposed regulations will vary as shown in Table 6, assuming a heating value of 12,000 Btu/lb. The sulfur content of these compliance coals is higher than the 1 percent level defined as low sulfur coal in many studies. Large quantities of coal with sulfur contents in the required ranges are used by the industrial sector in Ohio. Coal shipments to Ohio industry, not including electric utilities and coke and gas plants, in 1972 totaled 12,700,000 tons of which 11 percent contained 1.1 to 1.3 percent sulfur, 6 percent contained 1.4 to 1.8 percent sulfur, 35 percent contained 1.9 to 3.0 percent sulfur and the remaining 48 percent contained above 3 percent sulfur.[12]

Coal supply district 4 (all of Ohio) provides 53 percent of industrial coal consumed in Ohio while district 8 (southern West Virginia, parts of Virginia, eastern Kentucky and northern Tennessee) provides 40 percent.[13]

This industrial coal supply pattern is different from Ohio utility coal supply which consists of 64 percent district 4 coal, and only 15 percent district 8 coal. Therefore, it is evident that supply and transport

Table 6. SO_2 EMISSION LIMITATIONS AND EQUIVALENT PERCENT SULFUR IN COAL[a]

lb $SO_2/10^6$ Btu	Percent sulfur in coal
0.6	0.36
1.0	0.60
1.5	0.90
2.0	1.2
2.5	1.5
3.0	1.8
4.0	2.4
5.0	3.0
6.0	3.6
6.8	4.1

[a]Based on a heating value of 12,000 Btu/lb and 100 percent conversion of fuel sulfur to SO_2.

routes from district 8 are available to and utilized by Ohio industry. This is important because district 8 coal is commonly low in sulfur content and reserves of compliance coal are very large.

The reserve base of mineable coal in West Virginia, Kentucky and Ohio is presented in Table 7. These listed reserves include only measured and indicated coal seems greater than 28-inches thick and less than 1000 ft deep for deep mining and with less than 120 feet of overburden for strip mining. Reserves within these three states are large when compared to the 66 million tons/year currently used by all Ohio consumers. Perspective on the amount of reserves may also be gained by comparison of the current U.S. consumption of about 600 million tons/year to the West Virginia reserves of 40,000 million tons/total and 18,400 million tons of less than 1.5 percent sulfur coal. Even Ohio has significant reserves of coal that would comply with many of the regulations. A shift

Table 7. BITUMINOUS COAL RESERVE BASE FOR SELECTED STATES, THICKNESS, TYPE OF MINING, AND SULFUR RANGE - JANUARY 1, 1974 (MILLION SHORT TONS)[15]

	RESERVES BY SULFUR RANGE, PERCENT											
Thickness	≤ 0.4	0.5 - 0.6	0.7 - 0.8	0.9 - 1.0	1.1 - 1.4	1.5 - 1.8	1.9 - 2.2	2.3 - 2.6	2.7 - 3.0	> 3.0	Unknown	Total
West Virginia												
Deep > 28	229.19	2923.45	4946.83	2985.13	3696.23	2625.11	1437.13	2017.71	1779.23	4552.88	4142.90	34377.77
Strip > 28	44.12	799.33	1363.37	798.64	581.16	252.61	237.14	131.64	147.97	270.40	504.55	5212.02
Total	273.31	3722.78	6312.20	3783.77	4277.39	2877.72	1674.27	2149.65	1927.20	6823.28	4652.47	39589.79
Kentucky												
Deep > 24	0.00	0.00	0.00	0.00	0.00	0.39	1.19	70.44	314.56	7226.36	1107.11	8719.89
Strip > 24	0.00	0.00	0.00	0.22	0.83	8.53	22.22	45.20	101.05	2017.45	1708.79	3904.02
Total	0.00	0.00	0.00	0.22	0.83	8.92	23.41	115.64	415.61	9243.81	2815.90	12623.91
Ohio												
Deep > 28	0.00	9.09	37.49	68.87	318.26	693.25	954.59	1414.65	2068.83	10104.36	1754.09	17423.26
Strip > 28	0.00	2.97	5.27	10.63	41.55	93.05	192.70	310.27	353.39	2524.87	117.93	3653.85
Total	0.00	12.06	42.76	79.50	359.81	786.30	1147.29	1725.22	2422.22	12634.23	1872.02	21077.11

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in consumption patterns by Ohio industry which uses about 12 million tons of coal per year should not affect coal supply and prices. However, a change in consumption patterns by Ohio utilities and neighboring states may affect coal prices. There may be delays in opening new mines and if demand for compliance coal out-paces the increase in supply, prices will certainly increase. These complicating factors make the prediction of future prices very uncertain.

Many Ohio industrial facilities obtain coal by spot purchases. Prices for spot purchases, FOB mine, as reported in Coal Week during 1975 indicate that district 8 coal with a sulfur content of 1.25 percent was less expensive than Ohio coal with an average sulfur content of 3.2 percent. In December 1975 Ohio spot purchased coal was $17.5/ton and district 8 coal was $14.25/ton.[14] In his testimony at the January 8, 1976 public hearing, A. L. Susman, Chairman, Mines and Mining Subcomittee, West Virginia Senate, reported several indications of a lack of demand for low sulfur coal and significant idle mines capable of producing less than 1 percent sulfur coal.[15] When switching from one coal to another, many coal properties including ash composition, ash fusion temperature, moisture content, etc., can affect boiler performance.[17,18] Coal properties are less critical for stoker-fired boilers used at Union Camp. A suitable coal supply can only be determined on a case-by-case basis due to variations in the regulations and required fuel specifications. For the sites visited in this study GCA telephoned suppliers to determine current prices for coal with the required sulfur contents.

Mechanical coal cleaning has been widely used for many years and in 1973 about 50 percent of total coal consumption was cleaned coal.[19] Many of the systems now in operation, however, were designed primarily for ash removal. All coal used for coking (17 percent of total coal consumed and 33 of cleaned coal consumption) is cleaned to reduce both the sulfur and ash content. Coal cleaning technology is clearly commercially proven but its effectiveness depends on the properties of the specific coal

being cleaned. A summary of the application of mechanical coal cleaning in 1973 is presented in Table 8. Most West Virginia coal is cleaned but much greater sulfur reduction could probably be achieved through process improvements. On the other hand, less than half of Ohio coal production is cleaned and increased application of coal cleaning as well as improvement of existing systems could greatly reduce the sulfur and ash content.

Mechanical coal cleaning separates coal constituents with different specific gravities, as shown in Table 9. Sulfur is present in coal both as pyritic sulfur, which can be separated, and organically bound sulfur which cannot be mechanically removed. The pyritic sulfur composes 20 to 80 percent of the total sulfur with the lower percentage usually found in lower sulfur coals.[20] Analyses of Ohio coals indicates that about half the sulfur is present as organic sulfur.[21] Crushing frees the pyritic sulfur particles from other coal particles and is the first step in mechanical cleaning. Coal is commonly crushed to less than 1-1/2 inches or less than 14 mesh and smaller in certain cases. The finer size produces better sulfur removal but the crushed coal is harder to handle and cleaning costs increase. Wet concentration tables, compound water cyclones, air classification, froth flotation and concentrating spirals are widely used conventional commercially available methods for density separation in coal cleaning.[22] The net costs for mechanical coal cleaning are difficult to assess due to variations in coal washability. The Commerce Technical Advisory Board reported mid-1974 costs of $1.2 to $2.2/ton for crushing to 3/8 inch with single stage separation and $2.9 to $4.8/ton for a more elaborate multistage separation of finer particles.[23] Cost projections in Coal Age indicate a range of $6.6 to $9/ton to clean Appalachian coal to less than 1 percent sulfur.[24] An update by GCA of cost data reported by Battelle,[25] indicates a current coal cleaning cost of $6/ton of product for removal of pyritic sulfur for the conditions used by Battelle.

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Table 8. MECHANICAL CLEANING AT BITUMINOUS COAL AND LIGNITE MINES, IN 1973 BY STATE (THOUSAND SHORT TONS)[19]

State	Total production	Mechanical cleaning			
		Number of cleaning plants	Raw coal	Cleaned coal	Refuse
Alabama	19,230	19	18,433	11,705	6,728
Alaska	694	1	70	50	20
Colorado	6,233	3	1,933	1,662	270
Illinois	61,572	36	62,386	48,091	14,295
Indiana	25,253	10	25,330	19,699	5,631
Kentucky:					
Eastern	73,966	33	30,359	22,264	8,095
Western	53,679	18	26,004	20,005	5,999
Total	127,645	51	56,363	42,269	14,094
Ohio	45,783	17	20,799	14,588	6,211
Oklahoma	2,183	3	381	312	69
Pennsylvania	76,403	68	63,041	45,731	17,310
Tennessee	8,219	2	1,575	1,145	430
Utah	5,500	7	4,156	3,975	581
Virginia	33,961	32	26,559	17,696	8,863
Washington	3,270	2	4,460	3,262	1,198
West Virginia	115,448	124	107,520	75,672	31,848
Other States[a]	60,344	7	4,639	3,460	1,179
Grand total[b]	591,738	382	397,646	288,918	108,728

[a]Includes Arizona, Arkansas, Iowa, Kansas, Maryland, Missouri, Montana (bituminous coal and lignite), New Mexico, North Dakota (lignite), and Wyoming.

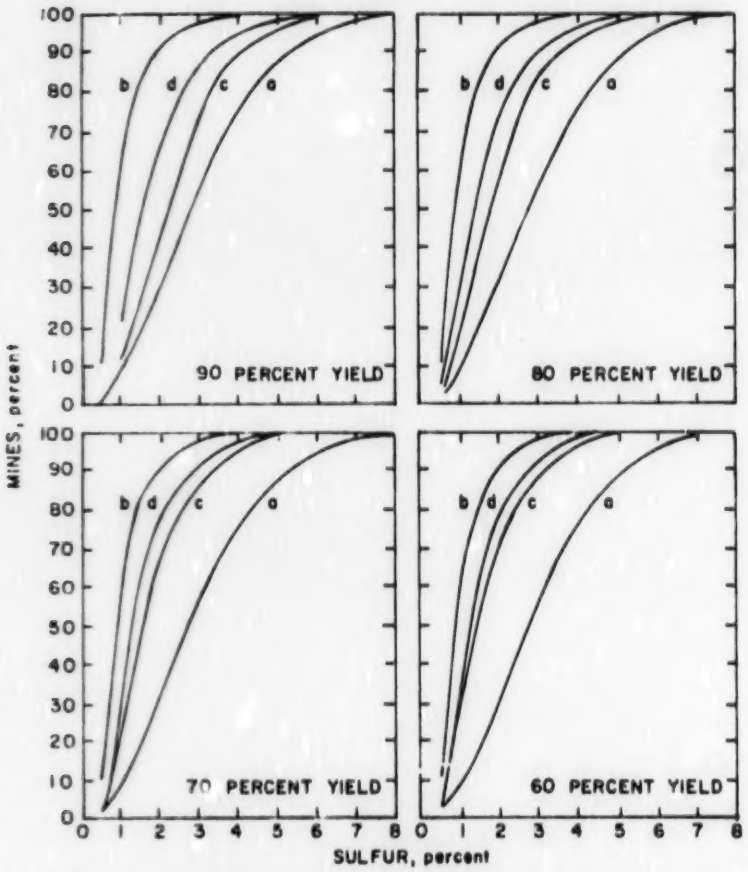
[b]Data may not add to totals shown because of independent rounding.

Table 9. SPECIFIC GRAVITIES OF COAL AND IMPURITIES

Material	Specific gravity
Bituminous coal	1.12 - 1.35
Bone coal	1.35 - 1.7
Carbonaceous shale	1.6 - 2.2
Shale	2.0 - 2.6
Clay	1.8 - 2.2
Pyrite	4.8 - 5.2

Washability studies conducted on Northern Appalachian coals (Maryland, Ohio, Pennsylvania, Northern West Virginia) showed that coals from 20 percent of the mines could be washed to less than 1 percent sulfur and coal from 65 percent of the mines could be washed to less than 2 percent sulfur at a 90 percent yield when curshed to -14 mesh.[22] These results are summarized in Figure 6. The washed coals discussed above contained only 5 to 7 percent ash and had a hesting value of about 13,000 Btu/lb.[22] Coals from the Northern Appalachian region are used extensively in Ohio. Washability studies were also conducted on Southern Appalachian coals, roughly equivalent to coal supply district 8, showing that samples from 90 percent of the mines could be reduced to less than 1 percent sulfur at a 90 percent yield when crushed to -14 mesh.[22]

Several cost benefits must be balanced against the coal cleaning costs. Coal cleaning reduces the ash content by 60 to 70 percent, and increases the heating content. Therefore, coal transport costs and ash handling and disposal costs are reduced. Boiler operation is potentially improved by reduced slagging, reduced need for particulate control, improved boiler availability and lower boiler operating and maintenance costs.[19] The Commerce Technical Advisory Board concluded that coal cleaning with or without additional FGD were the least expensive options for utility systems to meet the new source performance standard of 1.2 lb $SO_2/10^6$ Btu.[24]



(a) RAW COAL TOTAL SULFUR CONTENT CURVE;

(b) RAW COAL ORGANIC SULFUR CONTENT CURVE;

(c) WASHED COAL TOTAL SULFUR CONTENT COAL CURVE WHEN RAW COAL WAS CRUSHED TO MINUS 1 ½ INCHES; AND,

(d) WHEN RAW COAL WAS CRUSHED TO MINUS 14 MESH.

Figure 6. Washability of northern Appalachian region coals[22]

A small consumer like Union Camp would be unable to influence the application of coal cleaning. Union Camp might be able to purchase a small percentage of the output of a coal cleaning plant if a facility were built and operated by a mine. The use of coal cleaning by mining companies and/or utilities would expand the available supply of compliance coal.

SECTION IV

SO_2 EMISSION REDUCTION COSTS

The cost of complying with the proposed SO_2 regulation by flue gas desulfurization and switching to a compliance coal were evaluated. Flue gas desulfurization would require a total capital investment of $1.8 to $1.9 million and annual costs of $574,000 to $588,000 equivalent to $0.66 to $0.67/$10^6$ Btu of coal burned. Compliance coal to meet the proposed 3.2 lb $SO_2/10^6$ Btu standard is currently available at an incremental cost of $24,000 to $46,000 per year which is equivalent to $0.028 to $0.053/$10^6$ Btu.

FLUE GAS DESULFURIZATION

GCA contacted manufacturers of flue gas desulfurization to obtain budgetary cost estimates. Pertinent boiler design and operating data along with site layout diagrams were included in GCA's request for cost estimates. A summary of flue gas desulfurization system design requirements is presented in Table 10. At maximum capacity the system would have to handle 33,000 scfm. FMC provided cost data for their double alkali system and Research-Cottrell provided data for their Bahco lime scrubbing system. The costs of these systems were very similar.

Many systems are not applicable to boilers as small as those at Union Camp For instance, Combustion Engineering was also contacted but reported that they do not manufacture systems in this size range. Regenerative SO_2 control systems such as the Wellman-Lord system by Davy Powergas are also not economically competitive in the 33,000 scfm size range.

Table 10. SUMMARY OF FLUE GAS DESULFURIZATION DESIGN REQUIREMENTS

Flue gas flow at capacity, scfm	57,230
Flue gas temperature, ^{o}F	395
SO_2 concentration in flue gas, ppm	2,300
SO_2 emission rate, $lb/10^6$ Btu	6.48
lb/hr	1,290
Allowable SO_2 emission rate, $lb/10^6$ Btu	3.2
lb/hr	637
Emission reduction required, percent	51
Flue gas desulfurized,[a] scfm	33,000

[a] 33,000 scfm of flue gas could be treated at 90 percent SO_2 collection efficiency to achieve the required emission reduction. The remaining 24,000 scfm would be bypassed and used for reheat.

Utility, material and labor requirements at maximum rate capacity based primarily on data furnished by Research-Cottrell[26] and FMC[27] are presented in Table 11 for the 33,000 scfm system considered for Union Camp. Requirements for both systems were very similar. Because a large percentage of the flue gas will bypass the scrubber, steam or fuel for stack gas reheat is not required. Maintenance requirements were estimated to be 3.5 percent of fixed capital investment for materials and an equivalent amount for labor based on a TVA study of large systems.[28] Maintenance costs used in this study are on the high side of the probable range. Research-Cottrell based on operating experience at Cholla, reports that costs for their systems should be less than half those used in this study. Operation requirements are small with 0.25 to 0.5 men/shift required.

Annual costs for utilities, materials and labor are presented in Table 12. These costs are based on the requirements in Table 11, the unit costs in Table 12 and a typical yearly load factor at Union Camp of 50 percent. Total utility, material and labor costs are very similar, ranging from $228 to $231 thousand per year.

Table 11. UTILITY, MATERIAL AND LABOR REQUIREMENTS FOR FLUE GAS DESULFURIZATION AT UNION CAMP BASED ON MAXIMUM RATED CAPACITY

	Bahco lime (Research-Cottrell)	Double alkali (FMC)
Utility		
Power, kWh/day	4,520	4,720
Process water, 1000 gal/day	30	33
Material		
Lime (CaO), tons/day	6.6	7.7
Soda ash (Na_2CO_3) tons/day	-	0.5
Maintenance, percent of fixed capital investment per year	3.5	3.5
Labor		
Operation, men/shift	0.5	0.5
Maintenance, percent of fixed capital investment per year	3.5	3.5

Table 12. UTILITY, MATERIAL AND LABOR COSTS FOR FLUE GAS DESULFURIZATION AT UNION CAMP BASED ON MAXIMUM RATED CAPACITY AND A 50 PERCENT YEARLY LOAD FACTOR, $\$10^3$/yr

	Bahco lime (Research-Cottrell)	Double alkali (FMC)
Utility		
Power, $0.02/kWh	16.5	17.2
Process water, $0.20/1000 gal	1.1	1.2
Total utilities	17.6	18.4
Material		
Lime (CaO), $40/ton	57.8	56.2
Maintenance	63.7	60.6
Total material	111.9	116.8
Labor		
Operation, $8/manhour	35	35
Maintenance	63.7	60.6
Total labor	98.7	95.6
Total utility, material and labor	228.2	230.8

The capital and annualized costs as well as the individual components used to formulate these costs are presented in Table 13. These costs are current to June 1976. The most important capital costs, the installed costs of the battery limit plants were based on estimates by Research-Cottrell and FMC. Site preparation, including expenses to bring utilities to the battery limit plant and normal ducting, were estimated to be 20 percent of the battery limit plant based on similar costs in the literature. Retrofit difficulties at Union Camp were estimated to contribute an additional cost equal to 20 percent of the battery limit plant. Additional costs were based on Table 12 and on a cost analysis method derived from the Utility Financing Method as Modified by the Panhandle Eastern Pipeline Company.[25] Average annual control cost including capital cost, depreciation, operating expenses, etc., ranged from $574,000 to $588,000 for the two systems. These costs are equivalent to $0.40 to 0.42 per pound sulfur collected or $0.66 to 0.67 per 10^6 Btu of coal burned.

COST OF LOW SULFUR COAL

Because the coal-fired boilers at Union Camp are spreader stokers, required coal properties are not stringent. Union Camp is presently burning approximately 40,000 tons per year of coal containing 3.4 percent sulfur and having an average heating value of 10,500 Btu/lb. We estimate that Union Camp pays about $23 per ton of coal delivered or $1.095/$10^6$ Btu. To comply with the proposed regulation Union Camp would have to burn coal with a sulfur content of less than 1.7 percent if the heating value was 10,500 Btu/lb.

Island Creek Coal Company[29,30] has compliance coals available that would be suitable for use at Union Camp. These coals have sulfur contents between 1.35 and 1.45 percent with heating values between 13,500 and 13,800 Btu/lb. SO_2 emissions from these coals would be about 2 lb SO_2/ 10^6 Btu, well below the limit of 3.2 lb/10^6 Btu. These coals would cost $31 per ton delivered from Eastern Kentucky. Included in this cost would

Table 13. CAPITAL AND ANNUAL COSTS FOR FLUE GAS DESULFURIZATION SYSTEMS AT UNION CAMP, 10^3, JUNE 1976

	Bahco lime (Research-Cottrell)	Double alkali (FMC)
Capital Requirement		
Battery Limits Plant installed (BLP)	1,300	1,237
Site preparation and utilities, 20% of BLP	260	247
Additional retrofit requirements	260	247
Fixed capital requirement	1,820	1,731
Working capital,[c] 20% of gross operating cost	72.2	71.7
Total capital requirement	1,892.2	1,802.7
Annual Operating Cost		
Labor[d]	98.7	95.6
Administrative and general overhead, 60% of labor	59.2	57.4
Utilities[d]	17.6	18.4
Materials[d]	111.9	116.8
Local taxes and insurance,[c] 2.7% of fixed capital requirement	49.1	46.7
Solid waste disposal, $4/ton	24.6	23.4
Gross operating cost	361.1	358.3
By-product credit	0	0
Total annual operating cost	361.1	358.3
Annualized Cost		
Annualized capital cost[e]	192.7	183.6
Federal income tax[c,f]	34.0	32.4
Total Annual operating cost	361.1	358.3
Average annual cost	587.8	574.3
Average annual control cost, $/lb S removed	0.408	0.399
$/$10^6$ Btu input	0.674	0.659

[a] Manufacturer estimates, June 1976.

[b] Normal site preparation; cost to bring utilities to the battery limit plant and connect raw flue gas ducts to BLP based on GCA review of similar costs reported in literature.

[c] Based on Utility Financing Method as modified by the Panhandle Eastern Pipeline Company and described in Reference 25.

[d] See Table 12.

[e] Total Capital Requirement is amortized over 20 years at a discount cash flow rate of 8 percent. This works out to an effective rate of 10.185 percent per year of the Total Capital Requirement.

[f] Average Federal Income Tax = 1.731 percent of the sum of the total capital requirement and working capital.

be a trucking charge of $9.5 per ton. The total annual increase in fuel costs would be $24,400 to 46,200 per year, equivalent to $0.028 to $0.053/10^6$ Btu.

SECTION V

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